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Costs and Benefits of Renewables Portfolio Standards in the United States

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Abstract

Most state renewables portfolio standard (RPS) policies in the United States have five or more years of implementation experience. Understanding the costs and benefits of these policies is essential for RPS administrators tasked with implementation and for policymakers evaluating changes to existing or development of new RPS policies. This study estimates and summarizes historical RPS costs and benefits, and provides a critical examination of cost and benefit estimation methods used by utilities and regulators. We find that RPS compliance costs constituted less than 2% of average retail rates in most U.S. states over the 2010–2013 period, although substantial variation exists, both from year-to-year and across states. Compared to RPS costs, relatively few states have undertaken detailed estimates of broader societal benefits of RPS programs, and then only for a subset of potential impacts, typically some combination of avoided emissions and human health benefits, economic development impacts, and wholesale electricity market price reductions. Although direct comparison to RPS cost estimates is not possible, the available studies of broader RPS benefits suggest that in many cases these impacts may at least be of the same order of magnitude as costs, highlighting a need for more refined analysis.

1. Introduction

Renewables portfolio standards (RPS) require electricity providers to obtain specific amounts of renewable energy generation over time and are prevalent within the United States. In total, 29 U.S. states plus Washington DC have adopted some form of mandatory RPS requirement, with most policies enacted during the latter half of the 1990s and 2000s. Roughly 51 GW or two-thirds of all non-hydroelectric renewable capacity additions from 1998 through 2013 occurred in states with active or impending RPS targets, suggesting that these policies—alongside other state and federal policies and voluntary renewable energy markets—have played an important role in driving U.S. renewable electricity growth.[1]

With the proliferation of RPS programs has come renewed interest in understanding their costs and benefits. In recent years, this interest has frequently manifest within the context of legislative proposals to repeal or roll-back existing RPS programs, often on the basis that the policies impose undue burdens on utility ratepayers [7]. Aside from these politically charged debates, information about RPS costs is often needed as part of routine administrative and reporting functions. In particular, utilities or regulators are often required to estimate RPS compliance costs annually in order to fulfill statutory reporting requirements, to develop surcharges used to recover RPS-related costs, or to ensure that utilities do not exceed statutory cost caps [8] and [9]. Occasionally, states have also undertaken more expansive cost-benefit analyses, either on a prospective basis to inform the development of new RPS policies or, less frequently, on a retrospective basis to evaluate existing programs and inform possible revisions.

Estimating RPS costs and benefits entails a wide variety of methodological issues. In some states, certain aspects of the cost calculation methodology may be specified in statute or in implementing rules issued by the public utility commission (PUC), and a number of states (e.g., New Mexico, Minnesota, Washington) have recently conducted or initiated regulatory proceedings to develop consistent RPS cost calculation methods across utilities. In general, RPS cost estimates developed by utilities and regulators represent a net cost, accounting for avoided costs of displaced conventional generation. RPS programs, however, may also yield other forms of benefits or broader societal impacts, such as avoided air pollutant emissions, human health effects, reduced water consumption, fuel diversity, economic development, and electricity price stability. These broader benefits and impacts typically are not included within routine state or utility analyses, though they may be contained within occasional broader evaluations.

This article summarizes state-level RPS costs to date—drawing in part on original analysis and in part on a synthesis of estimates developed by utilities and regulators—and considers how those costs may evolve going forward given scheduled increases in RPS targets and cost containment mechanisms incorporated into existing policies. In doing so, the article seeks to provide a reasonably comprehensive empirical benchmark for gauging the costs of these important policies, and highlights key methodological issues critical to interpreting and refining cost estimates going forward. In addition, the article synthesizes available analyses of broader social benefits or impacts of state RPS programs, including emission and human health impacts, economic development, and wholesale electricity market price suppression—though, for a variety of reasons, the results of those studies are not directly compared to RPS cost estimates.

2. Methods

This analysis adds to a relatively small, but varied, literature analyzing RPS costs across states. At the national level, cost impacts of a proposed federal RPS have been studied with the use of modeling tools [10], [11] and [12]. At the state level, Morey and Kirsch [13] use regression analysis to examine the impact of various policies, including an RPS, on electricity rates, using historical data. Chen et al. [14] examined prospective, rather than retrospective, RPS studies, many of which were funded by nongovernmental organizations and were conducted to inform new RPS policies that were then under consideration.

2.1 RPS Costs

We estimate *incremental* RPS costs—that is, the net cost to the utility or other load-serving entity (LSE) above and beyond what would have been borne absent the RPS—during the period 2010-2013. We describe RPS compliance costs in terms of two metrics, though focus our discussion of results primarily on the second:

- *Dollars per megawatt-hour of renewable energy required or procured*, representing the average incremental cost of RPS resources relative to conventional generation;
- *Percentage of average retail electricity rates*, representing the dollar magnitude of incremental RPS costs relative to the total cost of retail electricity service (generation, transmission, and distribution).

In general, our RPS cost-calculation methods depend on the structure of the state's retail electricity market. In particular, for states with competitive retail electricity markets (herein termed "restructured" states), we generally estimate RPS compliance costs based on the cost of renewable energy certificates (RECs) and alternative compliance payments (ACPs). For states with traditional regulated, monopoly retail electricity markets, we instead synthesize RPS compliance cost estimates published by utilities and regulators, and highlight key methodological variations. Further details on the data sources and methods used to compute incremental RPS costs are provided below, with additional information in Heeter et al. [15].

2.1.1 States with Restructured Markets

Load serving entities (LSEs) in restructured markets typically meet RPS requirements by purchasing and retiring RECs, which represent the renewable energy attribute—in effect, the renewable energy premium above conventional power. RECs can be, and often are, transacted separately from the underlying electricity commodity. Moreover, because LSEs in restructured markets typically do not have long-term certainty regarding their load obligations, they often purchase RECs primarily through short-term transactions, although longer-term (10- to 20-year) contracting has become more prevalent recently, in order to improve the financeability of renewable generation projects. Most states with restructured markets include an ACP mechanism whereby an LSE may alternatively meet its obligations by paying the program administrator an amount determined by multiplying the LSE's shortfall by a specified ACP price (e.g., $50/MWh). ACP prices serve, more or less, as a cap on REC prices, because LSEs generally would not pay more than the ACP rate for RECs.

Many RPS policies divide the overall RPS target into multiple resource tiers or classes, each with an associated percentage target. These often consist of some combination of a "main tier" for those resources deemed to be most preferred or most in need of support (e.g., new wind, solar, geothermal, biomass, small hydro), one or more "secondary tiers" (e.g., for existing renewables that predate the RPS, large hydro, municipal solid waste), and a solar or distributed generation (DG) set-aside. REC pricing and ACP rates vary by tier, with the highest prices typically associated with solar/DG set-asides, followed by main tiers, and the lowest REC pricing for secondary tiers. REC pricing also varies by state, depending on many factors (e.g., the stringency of the target, eligibility rules, REC banking provisions, etc.). Pricing may be correlated among states in a region to the extent that renewable generators can sell RECs into multiple states in the region.

With a few exceptions, RPS compliance cost estimates for restructured states have not been developed. We therefore develop estimates of RPS compliance costs for these states, relying primarily on published data for REC and ACP prices and volumes, with slight variations for several states (New York, Illinois, Delaware).[2] For REC prices, we rely on data reported by public utility commissions (PUCs) for the average price of RECs used for compliance in each year, where available. If PUC-reported REC price data are unavailable, we instead rely on REC market bid-offer price sheets prices published by REC brokers, supplemented where possible with REC pricing data for long-term contracts with deliveries during 2010–2013. Data on the volumes of REC retirements and ACPs, along with ACP prices, were generally based on data published in utility or PUC compliance reports or otherwise obtained directly from PUC staff.

We translate REC plus ACP costs into an aggregate $/MWh cost by dividing by the sum total dollar costs of REC purchases and ACPs by the amount of renewable generation required in each year, and we translate REC plus ACP costs into a percentage of average retail electricity rates based on the volume of retail sales by RPS-obligated LSEs and average statewide retail electricity prices published by the U.S. Energy Information Administration [16].

The method and data sources used to compute RPS compliance costs for restructured states are subject to a number of important limitations that must be weighed when considering the results. First, by focusing exclusively on the direct costs associated with RECs and ACPs, this approach to estimating RPS compliance costs ignores certain costs, such as those related renewables integration or network transmission upgrades.[3] At the same time, RPS programs may result in additional cost savings for LSEs and ratepayers not captured in the REC and ACP-based approach – most notably, wholesale electricity market price suppression, which is discussed separately in Section 3.2. Second, broker-published REC price indices may be a poor proxy for the average price of all RECs used for compliance; thus, to the extent this source of data was used, some inaccuracy in the derived cost estimate may result. Third and finally, REC prices in a given state and year reflect the balance of supply and demand for RECs – rising to the ACP level if a state or region is undersupplied and falling precipitously if over-supplied. As a result, compliance costs derived from REC prices do not necessarily reflect the incremental cost to the electric system, per se, but rather the incremental cost borne specifically by LSEs. Notwithstanding the aforementioned limitations, we suggest that the compliance costs presented here represent a reasonable first-order estimate of the net cost of RPS policies borne by obligated LSEs in restructured states.

2.1.2 States with Regulated Markets

For traditionally regulated states, we do not develop independent estimates of incremental RPS costs, but rather leverage estimates developed by utilities and regulators in those states, and translate those data into a common set of metrics for comparison. These published cost estimates are typically contained within annual utility compliance filings or annual status reports issued by the state PUC; see Heeter et al. [15] for a list of the specific source documents.

The derivation of RPS compliance costs is considerably more complex in traditionally regulated states than in restructured states. This is because utilities in regulated states typically comply with RPS requirements through long-term power-purchase agreements (PPAs) with renewable electricity generators or by direct ownership of renewable generation, and the directly observable expenses associated with these resources include both the cost of RECs and the cost of the underlying electricity. Determining RPS compliance costs in these cases therefore requires an estimate of the cost of non-renewable generation avoided as a result of the RPS, to then be used as the benchmark for determining the incremental cost of RPS resources.

Not surprisingly, utilities and regulators have relied on widely varying approaches to estimate costs of avoided non-renewable generation, though in general these approaches fall into three general categories: the cost of a generic proxy conventional generator (e.g., a combined-cycle natural gas generator), wholesale electricity market prices, or production cost modeling. Some states may use a hybrid of these approaches, for example, using wholesale electricity market prices for avoided energy costs and the carrying cost of a combustion turbine as a proxy for avoided capacity costs. These varied avoided cost approaches each offer advantages and disadvantages; for example, wholesale market prices may be relatively simple and transparent, but may represent a poor counterfactual for the costs a utility avoids by virtue of procuring renewable electricity to meet its RPS. Conversely, modeling approaches may allow for a more comprehensive and realistic accounting of avoided costs and system-level interactions (including integration costs) but often require large amounts of data and complex models that are not easily vetted by regulatory staff and stakeholders.

Beyond the choice among the basic options identified above, a host of other inter-related methodological issues also vary across individual utilities and can substantially influence the calculated incremental costs, such as:

- Whether RPS compliance costs represent short- or long-term incremental costs, which in turn may influence assumptions about avoided generation capacity costs
- Whether to include costs of renewables procured prior to enactment of the RPS
- Whether to include costs of renewables procured beyond the minimum level needed to meet the target in a given year
- Whether to include indirect expenditures, such as integration, transmission, and administrative costs attributable to the RPS

- Whether to include incremental cost of energy efficiency programs in cases where some portion of the RPS target may be met with energy efficiency

Given our reliance on RPS cost estimates published by individual utilities and regulatory agencies, several important limitations apply to cost comparisons for regulated states. First, cost estimates are wholly unavailable for a number of states or are available for only a subset of utilities or years; thus the summary is less comprehensive than in the case of restructured states. Second, although we present data on a statewide basis, costs for individual utilities may vary significantly around the statewide average. Third, the methods and conventions used by utilities and regulators vary considerably and are often not completely transparent. The comparisons across states are thus imperfect. Finally, disconnects often exist in regulated states between the timing of RPS obligations and when costs are incurred. For example, utilities often procure renewable resources in advance of compliance obligations, and some utilities provide up-front incentives for renewable DG in exchange for RECs generated over each system's lifetime of operations.

2.2 RPS Benefits

The RPS incremental costs we report are net costs accounting for a narrow set of benefits—namely the benefits accruing to the utility in the form of reduced costs for non-renewable generation. However, policymakers have often pursued RPS policies due also to potential broader societal benefits or impacts [18] and [19]. Although relatively limited in number and scope, a number of states or utilities have conducted analyses of broader societal benefits of their RPS programs. Most are prospective in nature, assessing not only current RPS impacts but also future impacts, and have focused primarily on three types of impacts: avoided emissions and human health benefits, economic development impacts, and wholesale electricity price reductions.

We summarize the results of these benefits studies in Section 3.2, translating the estimated dollar impacts into units of dollars per MWh of renewable electricity generated, for the purpose of comparison. As will be discussed, however, the methods and level of rigor vary substantially, which limits the comparability of benefits across states. Comparison between benefits and costs is also challenging, because of potential double-counting (e.g., where emissions are already priced and therefore captured within incremental compliance costs) and misalignment of timeframes between cost and benefit estimates. In addition, certain quantified impacts—such as economic development and wholesale electricity market price suppression—may, in fact, be more precisely viewed as wealth transfers rather than true societal benefits. For these reasons and others, we stop short of providing a direct comparison between RPS compliance costs and the broader RPS benefits and impacts estimated within the set of studies examined.

3. Results and Discussion

The following subsections discuss the results of our analysis with regard to RPS costs (Section 3.1) and benefits (Section 3.2).

3.1 RPS Costs

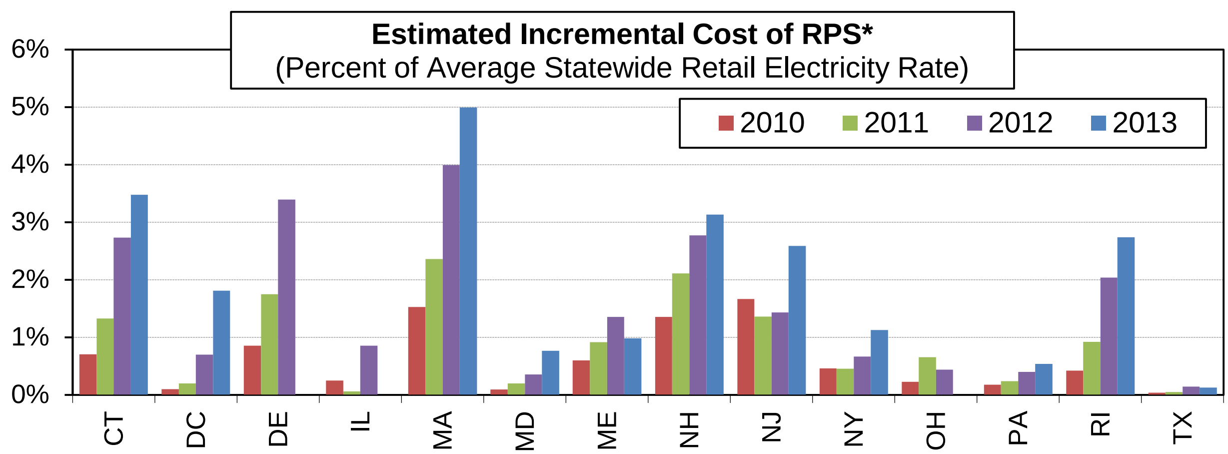
Our analysis of RPS compliance costs focuses on the 2010-2013 period, separately describing the costs in restructured and traditionally regulated states. We then illustrate the extent to which scheduled increases in RPS targets may put upward pressure on compliance costs, and highlight other drivers of future RPS costs. Finally, we show how existing RPS cost containment mechanisms may limit cost growth (and achievement of the RPS targets).

3.1.1 States with Restructured Markets

Based on the cost calculation approach described earlier in Section 2.1.1, RPS compliance costs in restructured markets during 2010-2013 ranged from well below $10/MWh of renewable energy generated in some states and years to upwards of $60/MWh in others, in large part reflecting differences in REC and ACP prices across states and years. For example, low main-tier REC prices in Maryland, Pennsylvania, and Texas led to correspondingly low incremental RPS costs in those states (less than $5/MWh). Conversely, relatively high main-tier REC prices among northeastern states, which rose over the period of analysis, led to correspondingly high and increasing RPS incremental costs in those states, rising to $37–$47/MWh in 2013.

Differing mixes of resource tiers within each state's RPS also contributed to variations in compliance costs. In particular, RPS costs were generally low for states with large secondary-tier targets, because REC pricing for those tiers is typically quite low, reflecting a typical surplus of supply for these lower-value resources. In Maine for example, the secondary tier (which consists primarily of existing large hydroelectric generation) constituted roughly 85%–90% of the RPS requirement each year, leading to overall RPS compliance costs of less than $5/MWh. Conversely, RPS compliance costs have tended to be higher in states with relatively high solar set-aside requirements, as SREC prices have generally been high compared to other tiers, though SREC prices have softened substantially in recent years. For example, New Jersey has relatively high solar set-aside targets—ranging from 4% of total RPS obligations in 2010 (when SREC prices averaged roughly $600/MWh) to 16% of RPS obligations in 2013 (by which time average SREC prices fell to $135/MWh). This combination of conditions contributed to relatively high average incremental RPS costs ($20–$30/MWh) over the 2010-2013 period.

Figure 1 expresses incremental RPS compliance costs as percentages of average retail electricity rates. In effect, these values would represent the impact of RPS compliance costs on retail electricity prices and consumer electricity bills were those costs passed fully and immediately to customers. Measured in terms of this metric, incremental RPS costs constituted less than 2% of average retail rates in most states during 2010–2013. In 2013, RPS costs averaged 1.2% of retail rates among restructured states with available data (on a weighted average basis, according to each state's retail sales), ranging from below 0.5% in several states to 3.5%–5.0% among most of the New England states. In general, the observed variations across states and years reflect the same kinds of differences as noted above (i.e., variations in REC and ACP prices and differences in the composition of the states' targets). In addition, and importantly, the RPS compliance costs shown in Figure 1 also reflect the stringency of RPS targets. It is for that reason that, in most states, costs increased over the period shown, as RPS percentage targets simultaneously rose.



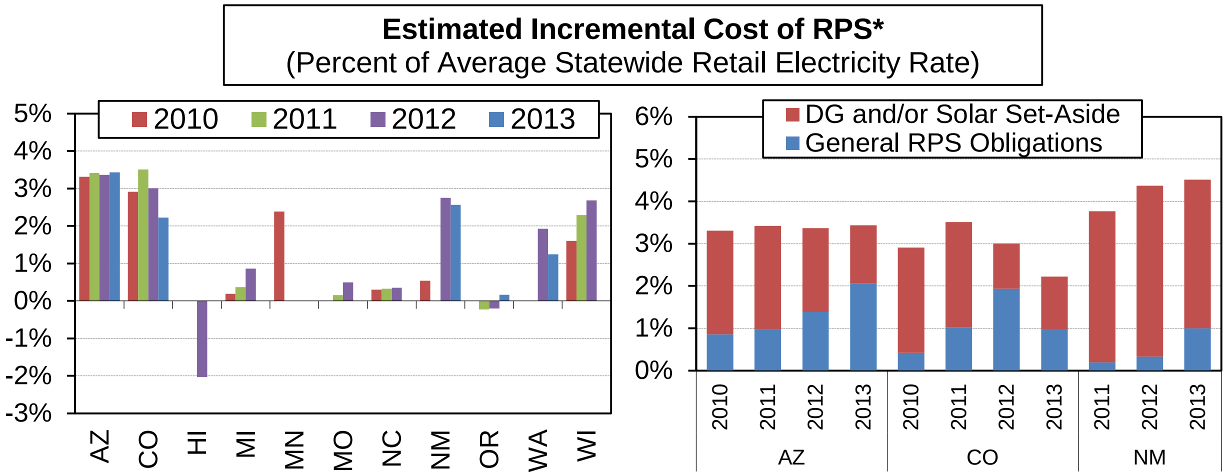
** Incremental costs are estimated from REC and ACP prices and volumes for each compliance year, which may differ from calendar years. If available, REC prices are based on average prices reported by the PUC (DC, IL, MD, ME, OH, NJ, PA); they are otherwise based on published spot market prices, supplemented with data on long-term contract prices where available. Incremental costs for NY are based on NYSERDA's annual RPS expenditures and estimated REC deliveries.*

Figure 1: Estimated incremental RPS cost over time in states with restructured markets (% of retail rates)

3.1.2 States with Regulated Markets

In traditionally regulated markets, compliance costs for general RPS requirements (i.e., excluding any solar or DG set-asides) were generally near or below roughly $20/MWh, ranging from -$25/MWh in Hawaii (2012) to $44/MWh in Wisconsin (2010). Cost variations among states partly resulted from different underlying renewable energy costs, but they also reflect differences in the methods used to calculate incremental costs. For example, the Wisconsin Public Service Commission estimated incremental costs using historical energy spot-market prices as the basis for avoided costs; those market prices were depressed in 2010, owing to the economic downturn, in turn resulting in relatively high calculated incremental RPS costs for that year. Regional electricity market prices rebounded in subsequent years, leading to declining RPS compliance costs in Wisconsin. In California, the PUC and utilities have used two different approaches to calculating avoided costs from RPS purchases—with the PUC relying on the all-in cost of a combined cycle gas generator and the utilities relying on wholesale electricity market prices. Using the PUC's avoided cost method yields RPS compliance costs equal to -$24/MWh in 2011 and -$4/MWh in 2012 (i.e., a net cost savings in both years), while the utilities' methods result in RPS cost estimates of $43/MWh in 2011 and $50/MWh.

Figure 2 presents incremental RPS compliance costs for regulated states as percentages of average retail electricity rates. As shown in the left-hand graphic of Figure 2, RPS costs for the majority of states shown were near or below 2% of average retail rates over the 2010-2013 period. Hawaii and Oregon are at the low end, both with negative incremental costs (i.e., net savings). Missouri also had very low costs because its utilities met their obligations largely or entirely with renewable resources procured prior to enactment of the RPS (for which incremental costs were deemed to be zero). In general, the values in Figure 2 reflect the totality of renewable generation procured by utilities each year, which in the case of most states was well in excess of the minimum RPS requirement. For Oregon and Missouri, the calculated costs are instead based on only those resources applied towards the RPS requirement in the years shown, although the utilities in those states also procured substantially greater amounts of renewables, banking the excess for compliance in future years.



** Incremental costs are based on utility- or PUC-reported estimates and are based on either RPS resources procured or RPS resources applied to the target in each year. Data for AZ include administrative costs, which are grouped in "General RPS Obligations" in the right-hand figure. Data for CO are for Xcel only. Data for NM in the left-hand figure include SPS and PNM in all years shown, but data in right-hand figure include only SPS. States omitted if data on RPS incremental costs are unavailable (CA, IA, KS, MT, NV).*

Figure 2: Estimated incremental RPS cost over time in regulated states (% of retail rates)

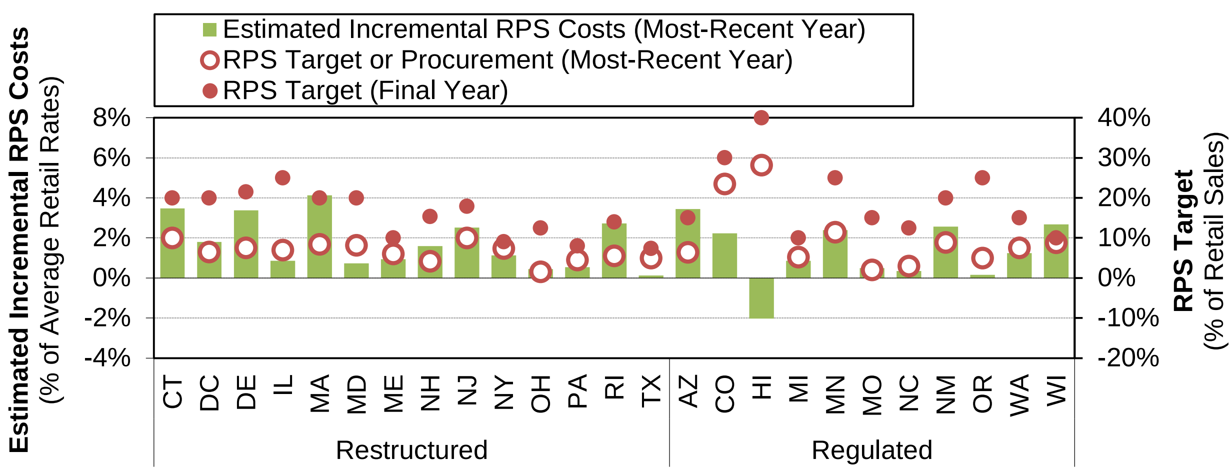
Estimated costs for Arizona, Colorado, and New Mexico were relatively high among the set of regulated states in Figure 2, for several reasons. As shown in the right-hand panel of the figure, DG and/or solar set-aside requirements in those states constituted the bulk of total RPS compliance costs in most years. That trend, however, is partially an artifact of the timing of costs for those resources: utilities meet those obligations in large part through rebates and performance-based incentives that are paid upfront (or over several initial years of production) in exchange for RECs delivered over each DG system's lifetime. As Figure 2 shows, those costs have declined over time, as utilities reduced incentive levels and moved away from upfront rebates. In addition, RPS costs in Colorado were relatively high because Colorado's RPS procurement levels were substantially higher than the levels in other states shown in Figure 2. The state's largest utility, Xcel Energy, attained renewable procurement levels equal to 15%–23% of retail sales during 2010–2013, compared to renewable procurement levels of 5%–10% in most of the other states shown.

The statewide averages presented in Figure 2 mask some variability in RPS costs among utilities in a number of states. In Washington, for example, all three investor-owned utilities and the state's largest municipal utility reported costs in 2012 of around 0.5%–1.4% of retail rates, but many of the smaller publically owned utilities reported higher costs (as high as 8%–9%). Minnesota utilities reported 2010 RPS costs of 0.1%–8.6% of average retail rates (most were around 1%–

3%). New Mexico's statewide averages are based on only two utilities, which reported costs of 1.5% and 4.5% in 2013. In general, intra-state variability is rooted in many of the same factors that drive differences in RPS costs across states (e.g., the cost and type of renewable energy resources procured, methodological differences, etc.).

3.1.3 Future RPS Costs

Comparing across all states, both restructured and regulated, and excluding any secondary resource tiers, RPS compliance costs ranged from -2.0% to 4.1% of average retail rates in the most recent year for which data were available (Figure 3). The corresponding RPS targets or procurement levels in those years (the open circles in the figure) ranged widely, from 2%–28% of retail sales, though in most cases fell within the band of 5%–9% of retail sales. Although certainly compliance costs in each state and year are impacted by the prevailing target or procurement level, other conditions also strongly impact RPS costs, including regional REC supply/demand balance, the presence of solar or DG set-asides, and cost-calculation methods.



** For most states shown, the most-recent year RPS cost and target data are for 2012 or 2013. MA does not have single terminal year for its RPS; the final-year target shown is based on 2020. Excluded from the chart are those states without available data on historical incremental RPS costs (CA, KS, HI, IA, MT, NV). The values shown for RPS targets and costs exclude any secondary RPS tiers (e.g., for pre-existing resources). For most regulated states, data for the most-recent historical year reflect actual RPS procurement percentages in those years.*

Figure 3: Estimated incremental RPS costs compared to recent and future RPS targets

That being said, RPS obligations are scheduled to rise going forward, reaching their peak in most states during 2020–2025, and those rising targets may place upward pressure on future RPS compliance costs. To provide an indication of this potential upward pressure, Figure 3 also shows the final-year RPS target in each state (the closed circles), which rise to 7%–40% of retail sales across the set of states shown and to at least to 15% in most states. Compared to the most recent RPS targets or procurement levels, final-year RPS targets constitute, on average, roughly a three-fold increase in RPS obligations.

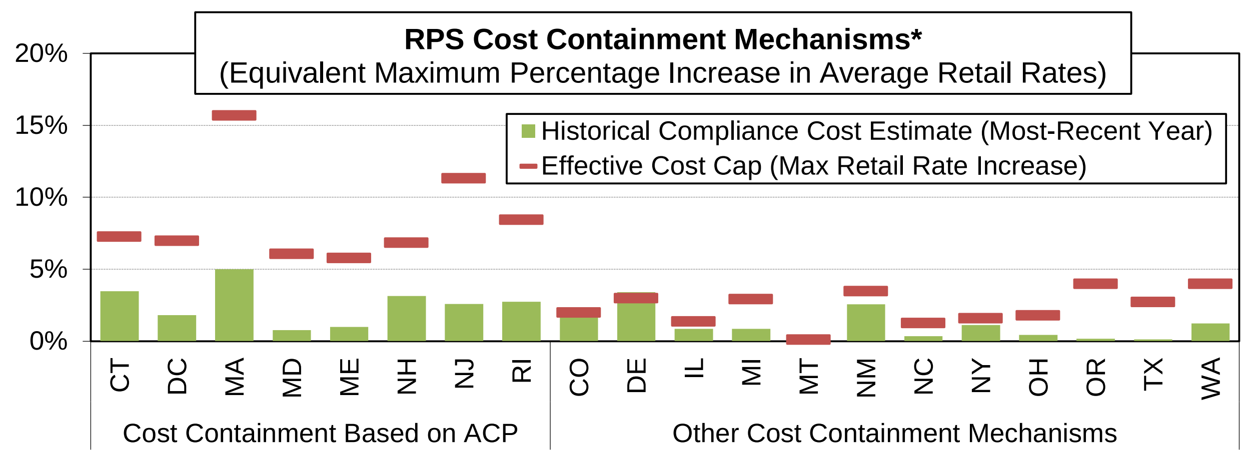
The trajectory of future RPS compliance costs will, of course, depend on other factors as well. First and perhaps foremost is the underlying cost of renewable energy technologies. Second is the price of natural gas, because gas-fired electricity is the typical baseline point of comparison for cost calculations in regulated states and can impact equilibrium REC pricing in restructured markets. Third, RPS costs may be strongly impacted by changes to federal tax incentives, most notably the investment tax credit for solar and production tax credit for wind and other renewables. Fourth, environmental policies, such as greenhouse-gas and air-pollution regulations, including EPA's recent Clean Power Plan proposal, could raise the cost of non-renewable resources and thus reduce the incremental cost of renewables. Finally, future RPS costs could be affected by cost-containment mechanisms built into many state RPS policies that, if they become binding, would limit attainment of the RPS targets (see Section 3.1.4).

Prospective RPS cost studies conducted for individual states or utilities help gauge the potential trajectory of future RPS compliance costs. Chen et al. [14] synthesized the results of 28 distinct state- or utility-level RPS cost impact analyses, finding that 70% of the studies in their sample projected retail electricity rate increases of no greater than 1% in the year that each modeled RPS policy reaches its peak percentage target. Five of the studies projected net reductions in retail rates, while two studies projected rate impacts greater than 5%. However, much has changed on the RPS landscape since that study. More recent analyses have estimated the following rate impacts for final target years: 10% in California [20], 2.2%–4.8% in Connecticut [21], 7.9% in Delaware [22], 1.1%–2.6% in Maine [23], 0.3%–1.7% for Northern States Power in Minnesota [24], 2.2% for Great River Energy in Minnesota [25], and -0.5% (a reduction) in North Carolina [26]. The scope, methods, and assumptions vary widely among prospective cost studies, limiting their comparability to one another and to the historical cost data presented earlier. They nevertheless suggest a range of RPS cost changes in response to rising targets.

3.1.4 Cost-Containment Mechanisms

Most RPS policies include one or more cost-containment mechanism, though as discussed in Stockmayer et al. [8], their efficacy may be imperfect. The most common approaches are ACPs and rate impact/revenue requirement caps. Other cost-containment mechanisms include surcharge caps, renewable energy contract price caps, renewable energy funding caps, and financial penalties for non-compliance. Beyond such prescriptive mechanisms, regulators in many states also varying forms of discretionary power that also provide a measure of control over RPS costs. The most explicit example may be cases where the RPS law explicitly grants authority to the PUC to delay or freeze RPS requirements or to issue waivers to individual utilities if costs are deemed excessive. In addition, PUCs in regulated states typically provide some level of direct oversight over utilities' procurement decisions and cost recovery, which may also serve to control compliance costs.

Figure 4 translates, where possible, existing RPS cost-containment mechanisms into the equivalent maximum percentage increase in average retail rates for the year in which each state's RPS target reaches its peak. In effect, these values represent the maximum potential annual RPS cost for the single year in which each state reaches its final target. To provide an indication of the level of head-room available in each state, Figure 4 also presents actual statewide-average RPS costs for the most recent historical year available.



** For states with multiple cost containment mechanisms, the cap shown here is based on the most-binding mechanism. MA does not have a single terminal year for its RPS; the calculated cost cap shown is based on RPS targets and ACP rates for 2020. "Other cost containment mechanisms" include: rate impact/revenue requirement caps (DE, KS, IL, NM, OH, OR, WA), surcharge caps (CO, MI, NC), renewable energy contract price cap (MT), renewable energy fund cap (NY), and financial penalty (TX). Excluded from the chart are those states currently without any mechanism to cap total incremental RPS costs (AZ, CA, IA, HI, KS, MN, MO, NV, PA, WI), though some of those states may have other kinds of mechanisms or regulatory processes to limit RPS costs.*

Figure 4: RPS cost caps compared to recent historical costs

Among states relying on ACPs for cost containment (grouped on the left in Figure 4), RPS costs are generally capped at 6%–9% of average retail rates. The effective caps are higher in Massachusetts (16%) and New Jersey (13%) owing to relatively high solar set-aside targets and/or ACP levels. Given that current RPS targets in these states are well below their final-year targets, recent RPS compliance costs are well below the effective cost caps. Rising RPS targets in these states, however, will not only require increasing volumes of REC purchases, but will also tend to put upward pressure on REC prices, which are already trading near their respective ACPs in many Northeastern states. At the same time, ACP rates generally will remain fixed (in real or nominal terms) or, in the case of many states' solar ACPs, will decline over time. This combination of possible upward pressure on REC prices and fixed or declining ACPs could constrain achievement of RPS targets and push total compliance costs toward the maximum levels shown in Figure 4. Tempering that trend will be any continued reductions in renewable energy costs and/or increases in wholesale power prices.

Among states with other, non-ACP forms of cost containment (grouped on the left in Figure 4), the effective cost caps are relatively restrictive, typically equating to 1%–4% of average retail rates. Cost caps have already become binding in several of these states (e.g., Illinois, New Mexico, and Missouri [not shown]). Several other states appear to have surpassed their caps, but for various reasons those caps have not yet been binding (e.g., Colorado, Delaware, and Kansas [not shown]). Other states are approaching their caps (e.g., North Carolina and Ohio). In Oregon, cost caps may become an issue for some utilities, even though historical compliance costs have been low. New York is also likely to hit its cap, although this is by design because the cap is based on a schedule of revenue collections adopted by the PSC and deemed necessary for achievement of the target. In Montana, the cost cap effectively prohibits any net cost from RPS resources. Texas and Michigan are both seemingly at low risk of reaching their cost caps, even though the caps are on par with other states within the group. In Texas, scheduled increases in the RPS target are relatively small, and installed renewable capacity in the state already well exceeds the final-year (2015) target. In Michigan, the cost cap is specified in terms of a maximum customer surcharge, and the state's two large IOUs reduced their surcharges substantially in 2014; both utilities project attainment of their RPS targets without any significant increase in surcharges [27] and [28].

3.2 RPS Benefits

Few studies have quantified the benefits of RPS policies. This section examines three categories of benefits that have been studied: emissions and human health, economic development impacts, and wholesale market price impacts. It is important to consider RPS benefits in conjunction with RPS costs. However, making direct cost-benefit comparisons—and benefit comparisons across states—is difficult because of the wide variety of methods and levels of rigor used for cost and benefit calculations, selective evaluation of only a subset of potential benefits, and possible overlap between costs and benefits (i.e., some benefits might already be included in some cost calculations).

3.2.1 Emissions and Human Health

One of the most often quantified environmental benefits of renewable energy is avoided air-pollutant emissions and associated human health benefits. Typically, estimates of avoided emissions focus on CO_2, sulfur dioxide (SO_2), and nitrogen oxides (NO_X). In some cases, the human health benefits of these reduced emissions are estimated by applying monetary values to, for example, the reduced morbidity or mortality from air-quality improvements. In other instances, monetary impacts are estimated based on the avoided cost of compliance with environmental regulations.

There are two common approaches to estimating RPS emissions impacts. The most robust approach is to conduct detailed modeling of the electric system with and without renewable generation to determine the mix of plants that would be operating and the overall system emissions in each scenario. This approach is best because it accounts for hourly operation—renewable facilities may displace different types of conventional generators throughout each day. A simplified approach is to estimate the marginal generating unit that would typically not be operating because of the renewable generator and apply the unit's emission rate to the displaced generation. This simplified approach yields approximate results.

Table 1 summarizes estimates of the emissions and associated monetary benefits from RPS policies for several states where data are available. Of the studies shown in the table, only the Maine study used a simplified emission rate method to estimate avoided emissions. All the others conducted more detailed electric system modeling to understand avoided emissions. Overall, estimates of air-quality benefits range from tens to hundreds of millions of dollars annually or about $4–$23/MWh of renewable generation. Some studies present a wide range of estimates depending on assumptions. Often, the value of avoided CO_2 emissions drives the estimates, because the magnitude of CO_2 reductions is largest. Assumptions about the value of CO_2 also influence results substantially. An interagency assessment of the social cost of carbon found a range of $11–$89/metric ton of CO_2 for the year 2010 (in $2007 dollars), depending on the discount rate used [29]. The NYSERDA study used a similar range for valuing avoided CO_2 emissions, while most of the other studies used a single estimate for CO_2 value, typically at the lower end of (or below) the interagency working group estimates.

Table 1. Summary of estimates of emissions and human health benefits of state RPS

State	Estimated Monetary Impact	Benefits $/MWh of RE	Period	Description	Source
CT	Not estimated	N/A	2020	Avoided CO_2 emissions of 0.39–0.53 tons/MWh of renewable generation	Brattle Group et al. 2010 [30]
OH	Not estimated	N/A	2014	CO_2 emissions reduced from 116.36 million metric tons in reference case to 116.16 (-0.17%), and to 115.79 (-0.5%) in scenarios	PUCO 2013 [31]
ME	$13 million	$7/MWh	Annual	Avoided allowance costs for 96 tons for SO_2, 1,629 tons for NO_X and 1.1 million tons for CO_2	LEI 2012 [23]
DE	$980–$2,200 million	N/A	2013–2022	Human health benefits due to improvements in air quality from emission reductions in power generation and other sectors	DPL 2012 [22]
IL	$75 million	$11/MWh*	2011	Avoided allowance costs for 5.5 million tons of CO_2 and 4,765 tons of NO_X	IPA 2013 [32]
NY	Not estimated	N/A	2002–2006	4,028 tons of NO_X, 8,853 tons of SO_2, and 4.1 million tons of CO_2	NYSERDA 2013a [33]
	$312–$2,196 million	$3–22/MWh	2002–2037	Value of avoiding 50.29 million tons of CO_2	NYSERDA 2013b [34]
	$48 million	$0.5/MWh	2002–2037	Value of avoiding 278 pounds of mercury, 15,214 tons of NO_X and 14,987 tons of SO_2	NYSERDA 2013b [34]

*Estimated based on 6.9 million MWh of renewable energy needed to meet the 2011 RPS requirements [35] and [36].

Many factors must be considered to compare emissions-reductions benefits with incremental costs. Where cap-and-trade policies are in place, RPS policies may not reduce emissions of capped pollutants unless there is a set-aside for renewable energy. Even in this instance, the increased production of emissions-free renewable electricity will reduce the cost of complying with the cap-and-trade program as approximated by the marginal allowance price. If allowance prices are used to estimate benefits, however, they must not already be captured in the estimated incremental cost of the renewable energy. For example, allowance prices should already be embedded in wholesale electricity prices, so, if wholesale prices are used in cost calculations, those estimates should already account for these impacts. Similarly, if a proxy plant used to calculate the incremental RPS cost includes allowance prices or carbon costs, then these emissions impacts are captured in the incremental cost assessment. The comparison is complicated further because benefits estimates are often forward looking, while the incremental costs are based on historical compliance. For these reasons, it is difficult to compare these estimates to the incremental costs discussed previously; however, treatment of these issues varies across states.

3.2.2 Economic Development Impacts

Policymakers often seek to achieve economic development goals with RPS policies, and in some states quantification of these impacts is required by law. The impacts include jobs, direct investment from construction and operation of facilities, tax revenues, and indirect and induced economic impacts, which result from the purchase of goods and services.[4] An RPS can also affect economic activity by influencing electricity prices. One key issue is whether the assessment examines gross impacts (e.g., new jobs supported) versus net impacts that consider shifts in employment. Understanding net impacts requires detailed analysis of changes in the operation of other generating units, fuel use, utility revenues, electricity prices, and residential and commercial energy expenditures [37]. Many states focus on impacts within their boundaries, but employment shifts can occur regionally. Furthermore, some assessments focus on only one aspect of the economic impacts.

The methods used for economic assessments have varying degrees of rigor. Simplified methods, which yield estimates of gross impacts, include input-output models or case-study approaches often focused on specific renewable energy facilities. Input-output models (e.g., IMPLAN, RIMS II)—the most common method for gross-impact analysis—calculate direct, indirect, and induced economic impacts by quantifying relationships between economic sectors at a point in time, but they cannot analyze changes in electricity prices. More sophisticated economic-modeling tools can assess net impacts, including econometric models that assess impacts on the economy as well as computable general equilibrium models (CGE models) that examine the flow of goods and services through the economy (see EPA 2011 [18] for detail on methods and models available).

Table 2 summarizes economic-impact estimates for RPS policies in several states. Overall, these states estimated economic impacts on the order of hundreds of millions of dollars for the construction period (one-time) and, in some cases, tens of millions of dollars in annual economic benefits over the project lifetime. These estimates translate to about $5–$27/MWh of renewable generation. One study found the RPS increased electricity prices and reduced gross state product by less than 1%. The methods and assumptions used to conduct assessments varied considerably across states. Illinois, Maine, Michigan, and Oregon conducted economic-impact assessments using input-output models, case studies, or anecdotal information on the impacts of renewable energy facilities; these typically assessed gross impacts. Connecticut and New York used more detailed modeling approaches, including econometric models; however, in some instances, they focused on only one economic-impact aspect of the RPS. Those studies that estimated gross impacts (e.g., jobs supported) do not consider net job impacts and thus cannot capture the true economy-wide impact of increased renewable-energy use.

Table 2. **Summary of RPS economic-impact estimates**

State	Benefit	Benefit/MWh of RE	Period	Description	Source
CT	Negative to positive gross state product (GSP) impact	N/A	Through 2020	Modeling showed retail electricity prices increased 0.86% to 3.48%, which reduced GSP 0.01% to 0.03%. One scenario showed an increase in GSP of 0.02%.	CEEEP and R/ECON 2011 [21]
IL	$5,980 million	$27/MWh*	25-year lifespan	Total economic impact at the state level of the 23 largest wind farms installed by 2012	IPA 2013 [32]
ME	$1,140 million	$4/MWh	Construction	2% increase in GSP	LEI 2012 [23]
	$7.3 million	$0.6/MWh	Annual, during project lifespan	$6.3 million annually in tax revenue for local governments and $1 million of revenue/year for private landowners during the operating life of the projects	LEI 2012 [23]
MI	$159.8 million	N/A	Construction	Economic impacts of four wind farms built in Michigan	MPSC 2013 [38]
NY	$1,252 million	$13/MWh	Project lifespan	Present value of the total direct investments in New York during the life of the projects	NYSERDA 2013b [34]
	$921 million	$9/MWh	Project lifespan	Cumulative impact on GSP	NYSERDA 2013b [34]
OR	Not estimated	N/A	Project lifespan	Estimated jobs resulting from renewable energy projects, based on survey	ODOE 2011 [39]

*Estimated assuming a 30% capacity factor and 25-year life.

3.2.3 Wholesale Market Price Impacts

Finally, some studies have attempted to assess reductions in wholesale market prices resulting from additional renewable generation (Table 3). Renewable generation can depress wholesale market prices by eliminating more expensive generating sources from the dispatch stack, which reduces the market clearing price paid to all generators. The studies summarized here estimated that each MWh of renewable energy reduces wholesale electricity prices by roughly $1/MWh, which translates into a renewable energy benefit of \$2–\$50/MWh of renewable generation. Typically, these wholesale-price estimates were derived through production cost modeling of the electricity system, running scenarios with and without the renewable generation on the system. The significance of these estimates is limited in a number of ways. First, wholesale-price suppression is a short-term effect that could change with changing market conditions. Second, these estimates focus on energy prices but do not assess capacity-related impacts or the need for new transmission or infrastructure investments that may be required with renewable generation. And third, although consumers benefit from lower wholesale market prices, the reductions represent transfer payments from generators to consumers, and therefore do not represent a net welfare gain to society.

Table 3. Summary of wholesale-market-price impact estimates for RPS renewables

State	Benefit	Benefit \$/MWh of RE	Period	Description	Source
ME	\$4.5 million	\$2/MWh	2010	Savings for consumers from reduced electricity prices. Extrapolating from a study by ISO New England, LEI estimated that 625 MW new wind in Maine would reduce wholesale prices by \$0.375/MWh of total Maine retail sales.	LEI 2012 [23]
MA	\$328 million	~\$50/MWh	2012	Savings for consumers from reduced wholesale electricity prices	EOHED and EOEEA 2011 [40]
IL	\$177 million	\$26/MWh	2011	Renewable energy lowers wholesale prices by \$1.3/MWh (all generation) due to low operating costs	IPA 2013 [32]
MI	N/A	N/A	2011	2% decline in wholesale prices attributed to wind generation, net imports, and decrease in load	Potomac Economics 2012 [41]
NY	\$455 million	\$5/MWh	Project lifespan	Savings for consumers from reduced wholesale energy and capacity prices	NYSERDA 2013b [34]
OH	Not estimated	N/A	2014	Renewable energy lowers wholesale prices by \$0.05–\$0.17/MWh (all generation)	PUCO 2013 [31]

4. Conclusions and Policy Implications

The policy implications of this work are several-fold. First, despite frequent claims that state RPS policies have imposed massive costs on ratepayers, experience to-date suggests that any rate impacts that have thus far occurred are likely quite modest, with compliance costs below 2% of average retail rates in most states. Going forward, RPS targets are scheduled to rise substantially in most states, which may exert upward pressure on compliance costs, though future RPS costs will also be heavily impacted by other market and policy dynamics. Some of those other drivers, such as reductions to federal tax incentives for renewables, may exacerbate upward pressure on RPS costs; whereas other dynamics—such as falling renewable technology costs, rising gas prices, and new federal environmental regulations—may serve to temper cost growth. Regardless of those uncertainties, cost containment mechanisms built into most existing RPS policies will limit cost growth to less than 10% of retail rates in most states, and in many states to less than 5%.

Our analysis also serves to highlight key methodological issues associated with estimating RPS costs, which are likely to become more critical as cost caps increasingly become binding. These methodological issues are perhaps most acute for traditionally regulated states, where RPS compliance is achieved primarily through bundled PPAs or utility-owned renewable generation. In these states, the central methodological issue is the approach used to estimate avoided non-renewable generation costs. As our comparisons suggest, and as the dueling cost estimates in California directly illustrate, the approach to this issue can substantially drive the ultimate result. Given the tradeoffs involved, and the widely varying market and regulatory conditions across states, a one-size-fits-all approach to estimating avoided costs is likely inappropriate and impractical. However, utilities and regulators may wish to take a fresh look at current practices, with consideration of methods used elsewhere, with particular attention to the methods used to estimate avoided generation capacity costs. Other key issues to consider include: whether to include costs of renewables procured prior to enactment of the RPS; whether to include costs of renewables procured beyond the minimum level needed to meet the target in a given year; and whether to include indirect expenditures, such as integration, transmission, and administrative costs attributable to the RPS.

For restructured states where compliance is achieved primarily through the purchase and retirement of RECs, perhaps the most fundamental constraint in developing reliable compliance cost estimates is a limited availability of representative REC pricing data, especially in states with growing reliance on longer term contracts. To address this limitation, several PUCs require individual suppliers to annually report the total cost of RECs retired for compliance each year, and broader adoption of this practice would greatly facilitate improved cost estimation. In addition, although rarely considered outside of occasional program evaluations, PUCs in restructured states may also wish to consider other RPS-related cost impacts (both positive and negative) to utilities and ratepayers, beyond the direct cost of RECs and ACPs. On the cost-side of ledger are integration-related costs, as well as any "socialized" transmission infrastructure costs directly attributable to new renewable generation. Although previous studies suggest that these costs would generally be small at current renewable energy penetration levels, such costs may become more significant as RPS targets ramp up. On the benefits-side of the ledger are the impacts of low-marginal-cost renewable generation supplies on electricity market prices (the so-called "merit order effect"). Although suppression of electricity market prices is properly construed as a wealth transfer between producers and consumers, rather than net gain in total social welfare and can be temporary, the study results nevertheless suggest that it may offset much of the direct costs of RECs and ACPs borne by LSEs.

Finally, further investigation of the benefits of these policies is important to ongoing policy-making efforts, particularly given that initial motivation for state RPS policies was often rooted in broader societal benefits and impacts. Unfortunately, relatively few states have undertaken analyses of these broader impacts, and where such studies have been conducted they've typically focused only a limited sub-set of potential impacts – most often, those impacts associated with emissions reductions and human health, local economic development, and wholesale electricity market price suppression. Although methodological differences among these studies preclude perfect comparison, the results to-date suggest that these impacts, in many cases, may be of the same order of magnitude as the incremental costs imposed on the electric system. As policy-makers consider changes to existing RPS programs or development of new programs, they may therefore wish to evaluate the broader societal impacts of state RPS programs, beyond simply a narrow consideration of the costs to electric utilities and ratepayers. Such efforts may be facilitated through the development of best practices or standardized methodologies and tools for estimating RPS program benefits.

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[1] A variety of other analyses – including Carley [1], Delmas and Montes-Sancho [2], Eastin [3], Shrimali and Kniefel [4], Yin and Powers [5], and Zhao et al. [6] – have sought to estimate the effects of RPS polices on renewable generation using econometric or other more-sophisticated means, and have found varied impacts, depending on the methods, scope, and timeframe of their analyses.

[2] Costs are calculated as: $C = \sum_{i=1}^{n}\left[\left(P_{REC,i} \times Q_{REC,i}\right) + \left(P_{ACP,i} \times Q_{ACP,i}\right)\right]$, where C is the calculated incremental compliance cost (in dollars) for a particular state in a particular compliance year, n is the number of resource tiers within the RPS, P_{REC} is the average annual REC price, Q_{REC} is the number of RECs retired for RPS compliance purposes, P_{ACP} is the ACP price, and Q_{ACP} is the number of ACPs issued.

[3] Although data on actual integration costs are not widely available, a variety of studies have modeled integration costs at much higher renewables penetration levels than currently exist in most RPS states (e.g., >20% of load served by wind), and have typically estimated integration costs less than $5/MWh of renewable energy generated [17], suggesting that our omission of integration costs does not substantially bias the results.

[4] See the RIMS II user's guide for more in-depth discussion of these components.